PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Item#68 I.D.# 5452

ENERGY DIVISION **RESOLUTION E - 3980**

April 13, 2006

R E S O L U T I O N

Resolution E-3980 - The 2005 Market Price Referents (MPR) are approved. 2005 MPR values have been calculated for use in the 2005 Renewable Portfolio Standard (RPS) solicitations.

This Resolution formally adopts the 2005 MPR values for a baseload proxy plant for the use in the 2005 RPS solicitations. This Resolution is made on the Commission's own motion.

SUMMARY

2005 MPR values have been calculated for use in the 2005 Renewables Portfolio Standard (RPS) solicitations.

This Resolution formally adopts the 2005 MPR values for a baseload proxy plant for the use in the 2005 RPS solicitations. This Resolution is made on the Commission's own motion.

The 2005 MPRs in the table below reflect MPR values calculated pursuant to D.04-06-015, D.05-12-042[1], and Staff recommendations.

Adopted 2005 Market Price Referents (Nominal - dollars/kWh)			
Resource Type*	**10-Year**	**15-Year**	**20-Year**
2006 Baseload MPR	0.08317	0.08178	0.08330
2007 Baseload MPR	0.07894	0.07926	0.08098
2008 Baseload MPR	0.07681	0.07817	0.08040
2009 Baseload MPR	0.07594	0.07811	0.08074
2010 Baseload MPR	0.07604	0.07882	0.08176
2011 Baseload MPR	0.07648	0.07973	0.08292
2012 Baseload MPR	0.07728	0.08095	0.08429

[1] Modified by D.06-01-029

*Using 2006 as the base year, Staff calculates MPRs for 2007 – 2012 that reflect different project on-line dates

BACKGROUND

Release of 2005 MPRs is consistent with prior Commission decisions

In D.04-06-015, we adopted a methodology to calculate MPRs for use in the 2004 renewable power solicitations, as generally set forth in Pub. Util. Code §§ 399.11-399.16.[2] D.04-06-015 set forth the following process under which MPRs would be disclosed:

> "[W]e conclude that the MPRs should be publicly and simultaneously disclosed to all parties after bidding has closed, but before completion of the utility's final short list. The MPR will be available to parties before negotiations are complete, to allow additions to the tentative short list, and the informed negotiation of payment streams. In order to implement this approach, each utility must notify the Commission via letter to the Executive Director that bidding has concluded, and that the utility expects to complete its tentative short list by a specified date. The Commission will coordinate the public and simultaneous disclosure of the MPR to all parties with this information in mind. After the parties have negotiated and finalized their bids based on subsequent release of the MPR, each utility will submit its final short list of bidders to the Commission staff and its PRG.[3]"

In addition, D.04-06-015 directed staff to prepare the MPR calculation and release it through a joint Assigned Commissioner and Administrative Law Judge (ALJ) ruling. Parties filed comments and reply comments on the staff report releasing the MPR calculation. Staff then prepared a Resolution for the adoption of the final MPR for 2004.

In view of the extensive work on the 2004 MPR and the more extensive record given careful consideration by the parties for the outstanding issues for the 2005 MPR, D.05-12-042 determined that a simpler process may be used now. D.05-12-042, modified by D.06-01-029[4], directs staff to prepare a draft Resolution on the 2005 MPR, including any relevant supporting materials as attachments to the draft resolution.

---

[2] SB 1078 (2002): An act to add Sections 387, 390.1, and 399.25 to, and to add Article 16 (Sections 399.11 - 399.16) to Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to renewable energy.

[3] D.04-06-015, p.29-30

[4] D.06-01-029 (OP #5, pg. 3)

The draft Resolution was released after all utility solicitations were closed. Parties had the usual opportunity to file comments and reply comments on the draft Resolution prior to its formal consideration by the Commission. [5]

The three IOUs submitted their letters to the Executive Director notifying the Commission that their solicitations were closed and the preliminary short-lists were complete:

- Pacific Gas & Electric (PG&E) – Solicitation closed on September 15, 2005[6]
- Southern California Edison (SCE) - Solicitation closed on October 15, 2005[7]
- San Diego Gas & Electric (SDG&E) – Solicitation closed on November 16, 2005 [8]

DISCUSSION

MPRs Were Calculated Using a Cash-Flow Simulation Methodology

The MPRs shown above were calculated using the SCE MPR model, a cash-flow simulation methodology approved by the Commission in D.04-05-015 and modified by Resolution E – 3942.[9] The SCE MPR model calculates what it would cost to own and operate a power plant over a 20-year period. The cost of electricity generated by such a power plant, at an assumed capacity factor and set of costs, is the proxy for the long-term market price of electricity.

The MPR model requires several types of input data, including natural gas prices, capital costs, operating costs, finance costs, taxes, and power delivery assumptions. The primary input drivers for the MPR calculation are the California (CA) gas price forecast, power plant capital costs, and the capacity factor for the baseload MPRs.

Note – Staff calculated the 2004 MPRs using the SCE Cash-Flow model and output from the MPR Gas Forecasting model. For 2005 and beyond, the two

---

5 D.04-06-015 (Footnote 21, p.30)

6 Per 12/20/05 email to CPUC Executive Director, PG&E issued its 2005 renewables solicitation on August 4, 2005 and closed it on September 15, 2005.

7 Per 3/14/06 letter to CPUC Executive Director, SCE issued its renewables solicitation on September 2, 2005 and closed it on October 18, 2005. On December 20, 2005, SCE notified the Commission that its 2005 RPS solicitation had closed. SCE completed its short-list of bidders and submitted that short-list to its Procurement Review Group on December 22, 2005.

8 Per 3/13/06 email to CPUC Executive Director, SDG&E issued its renewables solicitation on September 30, 2005 and closed it on November 16, 2005.

9 http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/48242.DOC

models have been merged together into one model, which Staff refer to in this resolution as the "MPR model."

MPR Based on CT Will no Longer be Calculated

In 2004 Staff calculated an MPR for a CCGT (baseload) and CT (peaker) proxy plant. In their 2005 MPR comments, PG&E and several other parties recommend that an MPR based on a peaking proxy unit not be adopted for use in 2005. Rather, the MPR for peak period energy should be established by applying factors derived through the TOD methodology to the baseload MPR. The application of TOD factors to the baseload MPR would eliminate the combustion turbine (CT) - based peaking MPR and the "blended" off-peak MPR (adopted in D.04-07-029).

PG&E noted that its proposal did not conflict with the statutory direction to establish a methodology to determine the MPR in consideration of "the value of different products including baseload, peaking, and as-available output."[10] TOD factors are based on the forward value of electricity during different TOD periods. Output from baseload, peaking, and as-available units may be time-differentiated by these periods, so the application of TOD factors to the MPR will result in a market price for each product and electric generating unit. Thus, it was not necessary to separately adopt an MPR based on the cost of an electric generating unit operated only during periods of peak demand.

D.05-12-042 agreed with PG&E that the application of TOD factors to the baseload MPR did take into account "the value of different products including baseload, peaking, and as-available output." Nothing in the statute requires the Commission to use multiple plant proxies in order to do so. Thus, D.05-12-042 ordered Staff to no longer calculate a CT-specific MPR based on the cost of an electric generating unit operated only during periods of peak demand.

MPR Gas Forecast Methodology and Inputs

D.04-06-015 noted that there is no transparent, liquid market for natural gas forward products for 10, 15 or 20-year terms, which is necessary in order to fuel a proxy power plant producing fixed-priced electricity over these time periods. Consequently, D.04-06-015 outlined a California gas forecasting methodology for years 1 through 6, and another methodology for years 7 through 20, both of

[10] Section 399.15(c)(3).

which are based on the forward Henry Hub (HHub) gas price that is basis adjusted to California.[11]

D.05-12-042, modified by D.06-01-029, refined the methodology for years 1- 6 by changing the 60-day-averaging period for the NYMEX forward prices to a 22-trading day averaging period, ending with the close of the utilities' solicitations.[12] For years 7 – 20, D.05-12-042 noted that parties criticized the methodology used in 2004 as not yielding consistent and explainable results using data from a variety of time periods and market conditions. Most notably, the gas prices for Years 7-20 were heavily (possibly too heavily) influenced by the forward gas price in the last year of NYMEX data used in the 2004 MPR forecast.

Consequently, D.05-12-042 adjusted the relationship between the end of NYMEX data (no later than Year 6, and possibly Year 5, see D.04-06-015) and the beginning of reliance on the fundamentals forecasts in Year 7 to address the problems with the forecast in 2004. D.05-12-042 determined that, instead of using the escalation forecasting methodology of the 2004 MPR for Years 7-20, Staff should use a three-year straight line blending between the near-term (Years 1-6) and the long-term (Years 7-20), and then use the average of the fundamental forecasts for the remaining years. This method retains the absolute value of the fundamentals-based gas price forecasts and eliminates the escalation process for Years 7-20 that we used in 2004, which was the subject of criticism from the parties.

The fundamental forecast for years 7 – 20 was developed using two private and one public 20-year Henry Hub fundamental forecasts[13]. Specifically, the public forecast was derived from the HHub wellhead prices provide in the U.S. Energy Information Administration (EIA) 2006 Annual Outlook[14]. With regard to the two private forecasts, they are private sector natural gas forecasts from Cambridge Energy Research Associates (CERA), PIRA Energy Group, or Global Insight. Due to contractual obligations requiring the CPUC to keep the forecasts confidential, staff can not reveal which of the three firms the forecasts were purchased from.

[11] "The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contract." (http://www.eia.doe.gov/oiaf/analysispaper/henryhub/).

[12] SDG&E's 2005 RPS solicitation finished (11/16/05) - after the SCE and PG&E 2005 RPS solicitations. Consequently, Staff used 11/16/05 as the last day in the 22-trading day averaging period.

[13] In 2004, 3 public forecasts and 1 private forecast were used, e.g., timely forecasts produced by CERA, PIRA, Global Insight, EIA, and the CEC.

[14] http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_19.xls

It should be noted that the EIA HHub forecast is extrapolated from the EIA's forecasted wellhead prices. Specifically, EIA examined the relationship between Henry Hub spot prices for natural gas and the U.S. wellhead price for the period spanning August 1996 through December 2000[15]. Their analysis determined the extent to which the two price series are linearly correlated and also evaluated the statistical properties of two simple price relationships—the actual difference and the percent difference. The results of the analysis indicated that there was a strong linear relationship between the two price series, to the effect that, on average the Henry Hub spot prices were 32 cents per thousand cubic feet (10.8 percent) higher than wellhead prices. The median value of the actual difference is 24 cents per thousand cubic feet, and the median value of the percent difference is 10.4 percent. Consequently, staff escalated the EIA wellhead prices by 10.8% to derive a proxy HHub forecast.

Please refer to:

- Appendix B for the 2005 California and Henry Hub 20-year gas forecasts (2006 – 2031)
- Appendix D for specific inputs used in the 2005 gas forecast

MPR Non-Gas Methodology and Inputs

Cost of Capital

Most parties,[16] with the exception of SCE, were critical of the financing assumptions used in the 2004 MPR. They asserted that those assumptions were internally inconsistent, having combined a merchant plant capital structure (70% debt/30% equity) with typical utility rates of interest on debt and return on equity. To address this concern in 2005, the Commission asked the parties to comment on three related aspects of the capital structure and cost of the proxy plant: financing of the proxy plant (project-based or total balance sheet); cost of capital for a proxy plant having a long-term PPA with a creditworthy IOU (same as IOU or different); and development of a specific weighted average cost of capital for a proxy plant having a long-term PPA with a creditworthy IOU.[17]

---

[15] U.S. Natural Gas Markets: Relationship Between Henry Hub Spot Prices - EIA Analysis (http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html)

[16] The CalWEA group, Green Power, PG&E, Solargenix, and TURN.

[17] Documents circulated to the service list on July 11, 2005 include: 2005 MPR workshop minutes, distrib. Parties, 7/11/05; PG&E email (July 5, 2005), "Summary of MPR Cost of Capital Financing Assumptions Meeting" with 2 attachments—070505 E3 Presentation, MPR Cost of Capital and 070505 PG&E Cost of Capital Presentation.

Based on several stakeholder meetings and party comments, D.05-12-042 adopted the following methodology for determining the financial inputs for the 2005 MPR:

1. Debt/Equity Ratio

D.05-12-042 noted that the proxy plant should be financed not as a stand-alone project, but on a total balance sheet basis. Most developers either are large corporate entities, or have more than one generation project; few if any have only one CCGT with one long-term PPA (the one being used as the proxy plant) in their portfolios. Therefore, D.05-12-042 adopted for 2005 the debt/equity profile of a proxy plant with a more conservative financing structure of 50%/50% rather than the 2004 MPR assumptions of 70%/30%.[18]

2. Cost of Capital

In their 2005 MPR comments, PG&E and SDG&E urged the Commission to use the utilities' cost of capital. They argued that a long-term PPA with a credit-worthy utility allows the generator to transfer almost all market and regulatory risk to the utility purchasing the power. The generator's risk would therefore closely approximate that of the utility. TURN, Green Power, Solargenix, and the CalWEA group, on the other hand, argued that an independent generator retains substantial risks, even with a long-term PPA with a creditworthy utility. These risks include construction cost overruns, operational performance problems, and ongoing capital and O&M costs that are higher than those contemplated by the PPA.

TURN also noted that a utility faced with similar problems could incorporate a request for funds to cover them in its next general rate case, while an independent generation developer has no comparable opportunity to ask for more money to cover forecasts that are shown to be inadequate. Thus, the utilities' financial risks are noticeably lower than those of an independent generator.

D.05-12-042 agreed with the non-IOUs that the risk profile of the proxy plant should fall somewhere between that of a merchant generator (selling into the market without a long-term contract) and a utility. So, having concluded that a capital structure similar to that of a utility is appropriate, but a risk profile the same as that of a utility is not, D.05-12-042 adopted the methodology parties referred to as "Option 2". The adopted methodology uses the cost of capital of

[18] While a developer could use the 20-year PPA and the strength of its balance sheet to increase the leverage in financing a particular project, the consensus of the parties is that the developer would use those characteristics to reduce the proportion of debt in project financing.

industrial companies in the Standard and Poor's 500 index (S&P 500) with risk profiles that are comparable to that of the independent power generation industry as a whole.

D.05-12-042 ordered Staff to make the appropriate clarification and to seek information that can be used for an annual update of the weighted-average cost of capital (WACC) for the proxy plant using the approach outlined by E3[19] in the "070505 E3 Presentation, MPR Cost of Capital" circulated to the parties on July 11, 2005. Based on the methodology outlined in E3's presentation, Staff calculated the financial inputs in the table below. See Cost_Cap Tab in the 2005 MPR model for a detailed calculation of the 2005 WACC.

2005 MPR Weighted-Average Cost of Capital

	DE Ratio	Cost	After-Tax
Debt	50.0%	8.03%	2.38%
Common Stock	50.0%	12.68%	6.34%
WACC	-	-	**8.72**

Heat Rate Adjustments

D.05-12-042 instructed staff to gather information from the manufacturer about the General Electric (GE) "F" series turbine, as well as information about the operation of California power plants, to determine how to adjust the 2005 MPR heat rate to reflect heat rate degradation, dry cooling, and start/stops. Staff selected the S207FA F-Series Turbine[20] from GE as the starting point for determining the operating heat rate.

Gas turbine degradation usually happens gradually over time, the net effect is that heat rate increases over time. The root causes include deposit of airborne material – particularly silica – on turbine blades at high temperature, erosion/corrosion of blading due to other airborne salts – particularly sodium, maintenance practices such as regular blade washing – on line or offline, number of starts and operating hours.

[19] Energy and Environmental Economics Consultants (www.ethree.com)

[20]http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf

Heat rate degradation can be classified as recoverable or non-recoverable loss. Recoverable loss is usually associated with compressor fouling and can be partially rectified by water washing or, more thoroughly, by mechanically cleaning the compressor blades and vanes after opening the unit. Non-recoverable loss is due primarily to increased turbine and compressor clearances and changes in surface finish and airfoil contour. Because this loss is caused by reduction in component efficiencies, it cannot be recovered by operational procedures, external maintenance or compressor cleaning, but only through replacement of affected parts at recommended inspection intervals. Quantifying performance degradation is difficult because consistent, valid field data is hard to obtain.

For the 2004 MPR, the Commission adopted a 3.5% heat rate degradation factor recommended by the parties. In its 2005 MPR comments, SCE recommended that Staff contact the manufacturer for a specific heat rate degradation factor. Using a heat rate degradation equation provided by GE,[21] Staff calculated the average heat rate degradation per hour of plant operation and adjusted the heat rate appropriately. Note – the average heat rate degradation factor, over the life of the plant, is 1.7%. This value assumes normal maintenance and off-line compressor water wash of the CC turbine and a major overhaul is conducted every 6 years (45-48,000 hrs), which brings the CC back to almost "new & clean".

Dry cooling is the second heat rate adjustment that D.05-12-042 required Staff to research and calculate. In its 2005 MPR comments (pg.6), CalWEA stated:

> The assumed heat rate must reflect the efficiency of dry-cooled plants. D. 04-06-015 found that the baseload MPR should be calculated using the costs of a dry-cooled CCGT.[4] For example, Calpine's dry-cooled Sutter and Otay Mesa plants are expected to have heat rates that are about 200 Btu/kWh higher than comparable wet-cooled plants.

SCE disagreed with CalWEA's proposed heat rate adjustment in its reply comments (pg.6), claiming that the adjustment is a function of plant location. Staff agrees with SCE that the impact of dry cooling on heat rate is largely driven by ambient temperature. However, given that the majority of CA's plants are being built inland, i.e., not desert or coastal locations, Staff made a simplifying assumption that the 1.5%[22] increase in heat rate for Sutter is an appropriate value use for the 2005 MPR. The adoption of this value is supported by the rule-of-

[21] See GE Tech. Notice - 101HA1567

[22] See the CEC's Final Certification Decision for the Sutter Power Project, Docket No.97-AFC-2, at 269

thumb adjustment (1.5%) recommended by GE for F-series turbines with dry cooling.[23]

Lastly, with regards to the Start/Stop impact on heat rate, parties noted that using a capacity factor lower than 92% will have an impact on the achieved heat rate, because the proxy plant will have less efficient operation when starting and stopping more frequently. Other parties agreed that the lower capacity factor could affect heat rate. Because we did not have quantitative information about the effect of lower capacity factor on heat rate, D.05-12-042 instructed Staff to collect information about the impact of a lower capacity factor on heat rate, and include such information, if relevant, in the staff calculation and supporting materials for the 2005 MPR draft resolution.

Staff contacted GE for a recommendation and was informed that without doing production cost modeling, 100 – 150 starts/year was an appropriate proxy value to use. This value assumes a must-run plant with a capacity factor between 85% - 92% capacity factor. Consequently, Staff selected 125 as a mid-point. For start-up fuel cost (MMBtu/MW), Staff used a value of 2.8 MMBtu/MW, which is based on CEC production cost modeling data (8/31/05). See Heat_Rate Tab in the 2005 MPR model for the specific calculation.

Capacity Factor

A critical issue raised by the parties is whether the MPR should continue to use the capacity factor of 92% adopted in 2004. This capacity factor assumes that the proxy plant is running essentially all the time, and captures the effects of both maintenance and unplanned outages. D.05-12-042 agreed with the IOUs that a developer with a fixed-price must-run contract, *paid a levelized price*, would find it economic to run in all hours, operate at full load in all hours, and can recover its fixed costs at a price that assumes the maximum feasible amount of generation.

However, D.05-12-042 pointed out that the introduction of Time of Delivery (TOD) profiles provide the generators with a market pricing signal. The generator is now paid a different $/kWh/TOD period depending on when it generates. The end result is that the generator will not operate in hours where its marginal costs are greater than its marginal profits, which will be something below 92% of the time.

Consequently, D.05-12-042 ordered Staff to calculate the capacity factor for the MPR CCGT by computing a capacity factor based on each utility's TOD profile

[23]http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4200.pdf

and then average the three MPR capacity factors to arrive at a statewide average capacity factor to be used in the final MPR calculation. This approach embraces the "market behavior" approach because we would be modeling what the owner of a new CCGT would do if it contracted with a California IOU.

The TOD capacity factor calculation developed by Staff determines the periods in which the TOD factor results in an MPR that is below the plant's variable operating costs. When operating revenues for a TOD period are below the variable operating costs, it is assumed that the plant will shut down for all the hours in that period. The variable operating costs are assumed to be the levelized MPR variable component calculated by the MPR model.

The calculation starts with an assumed technical capacity factor of approximately 92%: in this case the fixed costs for the referent plant are allocated over 92% of the year, or 8,087 hours. The calculation then estimates the number of hours the plant will shut down for economic reasons and calculates the resulting capacity factor, which may be lower, but not higher, than the technical capacity factor. If the capacity factor is lower, the fixed costs will be allocated over fewer hours (i.e. 88% or 7,735 hours). Thus, the lower capacity factor results in a higher MPR. The higher MPR in turn may reduce the number of hours that the plant shuts down, resulting in a higher capacity factor. Therefore, it is necessary to run the calculation iteratively until the result becomes stable or alternates between a higher and lower capacity factor. In the later case, the final result is the average of the high and low capacity factor. The MPR model is designed to iterate the calculation five times.

Calculating an economic capacity factor using TOD's is, by definition, a non-continuous or 'step' function. A plant is assumed to be on or off for all hours in a given TOD period (The off-peak periods with the lowest TOD factors total between 736-2,032 hours, or 8-23% of the year). In addition, the TOD's for off-peak periods may result in MPR's that are very close to the variable operating costs. Both these factors result in a capacity factor calculation that may be very sensitive to a change in the fixed cost, start up cost and TOD factor inputs. See the Cap_Fac Tab in the 2005 MPR model for the specific calculation

<u>Baseload Capital Costs</u>

The 2004 MPR was based on the CEC Cost of Generation Report's estimate of $616/kW (2004$) for installed capital costs. Using the CEC's Cost of Generation model, Energy Division calculated a value of $720/kW for the CCGT baseload resource, making adjustments for interconnection costs, environmental permitting costs (aside from emissions), additional capital costs for dry cooling, and contingency costs.

However, in 2005, several parties recommended that the Commission use values that reflect the actual cost of a range of CCGT projects that have been built in the last few years or are currently under construction in California. TURN further argued that the Commission should not use the current market survey data obtained from the Energy Commission's application for certification (AFC) process (input for CEC's Cost of Generation Model), but should only use actual data from operating projects after initial commercial operations, or from those under construction, and subject to independent audit.

D.05-12-042 adopted the above recommendation that the market survey of plants most recently constructed or currently under construction should be used when identifying specific input values. [24] D.05-12-042 also adopted additional criteria for conducting a market survey of plant costs. Specifically, Staff was ordered to use the following as suggested criteria in selecting plants to survey:

- 500 MW CCGT (approximate)
- Utilizes GE "F-Series" turbine
- Located in California

Staff identified the installed capital costs for the 2005 MPR CCGT proxy using the reported capital costs ($ per kW) of comparable CCGT plants. To find comparable plants, Staff started with the list of existing and planned CCGT plants within the Western Electricity Coordinating Council (WECC) found on the CEC's "Energy Facility Status" website.[25] Using the survey criteria outlined above, Staff identified the following plants that had publicly available cost data:

- Palomar (SDG&E)
- Cosumnes (SMUD)

---

[24] The Energy Commission's cost of generation report is produced roughly biannually. The August 2003 Comparative Cost of California Central Station Electricity Generation Technologies report, www.energy.ca.gov/reports/2003-08-08_100-03-001.PDF, is the most recent. This report was prepared in support of the Energy Commission's 2003 Integrated Energy Policy Report (IEPR) Subsidiary Volume: Electricity and Natural Gas Assessment Report (www.energy.ca.gov/2003_energypolicy/index.html).

The Energy Commission does not plan to adopt its new cost of generation report in time for the 2005 MPR calculation. Analysis relevant to the 2005 MPR may, however, be available at a staff level. D.05-12-042 directs staff to confer with Energy Commission staff to determine what information and analysis related to the cost of generation may be available for use in the 2005 MPR.

[25] http://www.energy.ca.gov/sitingcases/all_projects.html

Based on the plants listed above the average installed capital cost, reflecting interconnection costs, environmental permitting costs (aside from emissions), additional capital costs for dry cooling, and contingency costs is $939/kW (2006$). Please refer to Appendix C for a detailed discussion regarding how the installed capital cost for the 2005 MPR was derived.

Fixed and Variable O&M Costs

In its reply comments (pg. 9), PG&E stated that the SCE Benchmark Study of Operation and Maintenance (O&M) values sponsored by SCE witness Joe Wharton before the FERC on behalf of Edison in the Mountainview case contains a wide range of O&M values and provides a reliable starting point for the Commission's quantification of O&M costs.[26] PG&E and CalWEA also agreed that the survey should be augmented by the Palomar O&M data. However, PG&E recommended discarding the extreme high and extreme low values, that is, the fixed O&M values for EOB of $36.09/kW-yr and for Mountainview of $8.70/kW-yr. Giving each remaining source (plus Palomar) equal weight, the final fixed O&M value should be $13.92 / kW-yr.

Staff adopted PG&E's proposal with modifications:

- Removed EOB and Mountainview from the Wharton O&M data set
- Added Contra Costa 8 and Palomar
- Updated the EIA value using EIA's 2006 Annual Energy Outlook Report[27]

2005 MPR Fixed and Variable O&M

Data Source	Fixed O&M (2006$)	Variable O&M (2006$)
Palomar	13.84	3.18
CC8	14.94	1.84
2006 EIA	11.01	3.29
Henwood	10.41	2.08
CERA	16.01	1.07
CEC	16.01	2.54
Stone & Webster	N/A	3.01
Average	$13.70	$2.43

[26] CCC/CalWEA has quoted Mr. Wharton's table at page 12 of its opening brief.

[27] http://www.eia.doe.gov/oiaf/archive/aeo05/assumption/pdf/0554(2005).pdf

Additional Modifications to the 2004 MPR Methodology

1. Nominal MPRs Reflecting Different Project On-line Dates

In their 2005 MPR comments, CalWEA group, SCE, PG&E, and SDG&E agreed that the MPR should be calculated in nominal dollars[28] for two reasons. The bid prices of projects are expressed in nominal dollars. In addition, since the utility is guaranteed recovery of renewable power purchase costs at or below the MPR, there should be no ambiguity regarding the comparison of bid prices with the MPR.[29] The parties[30] also agreed that it was beneficial for the Commission to calculate a series of MPRs for different project on-line dates. Since bidders express their final contract prices in nominal dollars, and projects may require several years' lead time before deliveries begin, the Commission should calculate a series of MPRs corresponding to different project on-line dates in 2006 through 2012.

Consequently, D.05-12-042 reaffirmed the approach of calculating nominal MPRs reflecting different project on-line dates, as original adopted in Resolution E-3942.[31] So, for the 2005 MPR calculation, Staff assumed that after the 5-year period (after 2010), technological improvements would offset the escalation of capital costs, so no further inflationary adjustments need to be made to the installed capital costs. Pursuant to D.05-12-042, the 2006 - 2010 capital costs were escalated using a specific inflation index focused on changes in the cost to construct plants.[32] See CF_Data Set Tab in the 2005 MPR model for the specific calculation.

2. Using Straight-line Depreciation to Calculate Property Tax

---

28 Nominal dollars are economic units measured in terms of purchasing power of the date in question. A nominal value reflects the effects of general price inflation. Real or constant dollar values, by contrast, are economic units measured in terms of constant purchasing power. A real value is not affected by general price inflation. Real values can be estimated by deflating nominal values with a general price index, such as the implicit deflator for Gross Domestic Product or the Consumer Price Index. (www.nps.navy.mil/drmi/definition.htm.)

29 "Procurement and administrative costs associated with long-term contracts entered into by an electrical corporation for eligible renewable energy resources pursuant to this article, at or below the market price determined by the commission pursuant to subdivision (c) of Section 399.15, shall be deemed reasonable per se, and shall be recoverable in rates." (Section 399.14(f).)

30 CalWEA group, ORA, PG&E, and SDG&E.

31 Cite resolution 3942, which adopted the 2004 MPR

32 Installed capital costs were escalated using the US Army Corp of Engineers Escalation Index (CWBS Feature Code 07 - Updated Sept 30, 2005). Insurance, FOM, and VOM were escalated using the EIA 2006 GDP Chain-Type Price Index.

Per D.05-12-042, Staff adopted the straight-line depreciation method for calculating the property tax of the proxy plant. See Fixed_Comp Tab in the 2005 MPR model for the specific calculation.

3. GMM – 20-Day Average vs. 365-Day Average

In its 2005 comments, CalWEA asserted that the assumption in the 2004 MPR of a 98.57% Generation Meter Multiplier (GMM), should be revised. This value was derived from a sample of generator GMMs from a two-week period in December 2004. The CalWEA group noted that GMM values can be much higher during the summer months, when the transmission system is more heavily loaded. Because the utilities track the CAISO's system average GMM on a daily basis, they possess the data needed to calculate system average GMMs for all generators on the CAISO grid, over all days of the year.

The CalWEA group therefore recommended using these system average GMM values for 2004 in the 2005 MPR, in order to provide more representative statewide values than the two-week snapshot of GMMs used for the 2004 MPR. D.05-12-042 conditionally adopt CalWEA's proposal and directed staff to finalize the specific method for determining GMM values. Staff submitted a data request to the CAISO for the simple average GMM of all the generating resources for each hour in 2005. Using CAISO data, Staff calculated the 2005 statewide average GMM to be 98.51%.

Please refer to Appendix E for a summary of the 2005 MPR non-gas inputs.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this Resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this Resolution was neither waived nor reduced. Accordingly, this draft Resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from March 14, 2006.

On March 30, 2006, timely comments were filed by California Wind Energy Association (CalWEA), Pacific Gas & Electric (PG&E), Southern California

Edison (SCE), San Diego Gas & Electric (SDG&E). Reply comments were filed by CalWEA, PG&E, and SCE on April 6, 2006.

1. CCGT Plants used to Determine Installed Capital Costs

The Draft Resolution assumes the installed capital cost/MW of the 2005 baseload MPR is the average of the installed capital costs/MW of four CCGT plants (Mountainview, Palomar, Cosumnes, and Contra Costa 8). PG&E states in its comments that the Contra Costa 8 and Mountainview plants should not have been used because there is insufficient information on the record to overcome the presumption against their use that was established by the 2005 MPR decision.

PG&E argues that the adjustments that the Draft Resolution made to the amounts paid for Contra Costa 8 and Mountainview, in an attempt to overcome these Commission concerns, are inappropriate, because those adjustments are based on misinterpretations of information drawn from other filings.

The Contra Costa 8 (CC8) plant is a partially finished CCGT whose fate is still uncertain: if Mirant's sale of the plant to PG&E is not completed, Mirant will pay PG&E $70 million in lieu of the plant pursuant to the terms of their litigation settlement. In fact, the $70 million does not pertain to the market value of the existing assets that PG&E will receive in its settlement. The Asset Transfer Agreement requires Mirant to use commercially reasonable efforts to obtain the permits and other regulatory approvals. The $70 million provides an additional inducement to focus Mirant on obtaining the proper permits for CC8. Furthermore, the $70 million is not an unfettered option. PG&E may take the $70 million only if certain triggering events occur that are related to the viability of the potential development, not to the market value of the facility.

PG&E notes that in the 2005 MPR Decision, the Commission specifically considered the use of CC8 as a capital cost proxy and recognized that there may have been "trade-offs in the price of the CGT in exchange for other considerations", rendering the price of the CCGT unsuitable for the purpose of setting the MPR in the absence of an adequate benchmark. The Draft Resolution does not provide a benchmark by which the CC8's cost of capital may be judged. Therefore, PG&E argues that CC8 should be not be used in deriving the installed capital cost of the proxy MPR CCGT.

With regards to Mountainview, PG&E states in its comments that the Commission determined in D.03-12-059 that Mountainview's purchase price reflects a capital cost that is significantly below that of any comparable new facility and substantially below such a facility's market price. Therefore, the amount SCE paid for Mountainview is not relevant to and cannot be adopted as the market price referent used in any solicitation conducted pursuant to the California RPS program. Moreover, in D.05-12-042, Commission conditioned its consideration of "distressed" projects such as Mountainview on the existence of adequate data are available to serve as the benchmark for the project. No benchmark has been adopted in a litigated Commission proceeding.

In its comments, SCE argues that the Commission was incorrect in adopting CalWEA's recommendation that Mountainview installed capital costs should be inflated 20% to reflect a 20% discount to the cost that SCE would have paid to develop and build the project from scratch. Specifically, in its FERC filing seeking approval of Mountainview power purchase agreement, SCE presented an affidavit stating that Mountainview's capital costs were approximately 8% below that of comparable CCGT plants.[33] Therefore, Mountinview's installed capital should be inflated by 8%, not 20%.

In its reply comments SCE does not offer an opinion as to whether CC8 should be used in the MPR calculation, but does disagree with PG&E's recommendation that Mountainview be exclude from the calculation. Furthermore, if the Commission adopts PG&E's suggestion to exclude both CC8 and Mountainview from the MPR model, the Model's calculation of the installed capital costs of the MPR proxy would be based on data from just two CCGT plants, Palomar, and Consumnes. SCE argues that this is an insufficient sample to determine the installed capital costs for the MPR proxy plant.

Staff agrees with PG&E that there is inadequate record to determine the market price of CC8 and Mountainview. Consequently, the installed capital cost section in the Resolution and in the MPR model have been modified to only reflect the installed capital costs of Palomar and Consumnes. Staff agrees with SCE that using only two plants to calculate installed capital costs is less than ideal. However, given the limited CPUC record and the reluctance of merchant developers to disclose confidential cost data, Staff are constrained by the limited data that is publicly available. For future MPR calculations, Staff will work with the parties and the CEC to identify ways to expand the installed capital costs dataset.

2. Consistency Between Installed Capital Costs and Nameplate Generation

[33] SCE's December 19, 2003 Mountainview Application to FERC, FERC Docket ER04-316, Attachment F, Affidavit of Joseph B. Wharton (attached as Appendix A to SCE's opening comments)

In its comments, SDG&E notes that the Draft Resolution uses average installed capital costs, but provides no indication that capital costs related to construction of facilities associated with peaking service were excluded from the installed capital costs used to develop the average. Consequently, SDG&E recommends that the Commission use the use the peaking load nameplate rating (555 MW) rather than the baseload nameplate rating (500 MW) to determine Palomar's installed capital costs on a $/kW basis.

In its reply comments, PG&E supports SDG&E's proposed modification. In contrast, CalWEA states in its reply comments that the peaking capacity associated with Palomar should not be reflected in its $/kW capital costs. Consideration of the peaking capacity associated with a CCGT would result in an understatement of the $/kW costs of a baseload plant. Staff agrees with SDG&E that development of accurate MPRs requires consistency between capital cost assumptions and output capacity assumptions. Consequently, Staff modifies the installed capital cost calculation in the Resolution and the MPR model to reflect Palomar's peaking nameplate rating.

3. 50/50 Debt – Equity Ratio

In their comments, SDG&E and PG&E note that the 2005 MPR decision held that "It is reasonable to treat the MPR proxy plant as a having a ratio of debt to equity of 50%/50%."[34] However, the Draft Resolution MPR model uses market data to recalculate a capital structure consisting of 42.5% long-term debt and 57.5% equity. SDG&E and PG&E argue that the capital structure should be changed to the 50% debt/50% equity capital structure adopted in D.05-12-042. In its reply comments, SCE supports SDG&E and PG&E's proposed change.

Staff adopts the proposed change and modifies the 2005 Cost of Capital calculation in the Resolution and in the MPR model to reflect a 50/50 debt to equity to ratio. However, it should be noted that Staff will recalculate the debt to equity ratio, pursuant to the adopted E3 weighted – average cost of capital methodology, in future MPR calculations. It would be inconsistent to calculate a WACC based on the latest market data without adopting the underlying debt to equity ratio.

4. Modify the Capacity Factor Calculation

In the Draft Resolution, Staff determined a 91.7% capacity factor based on an iterative methodology that uses RPS time-of-delivery (TOD) factors, applied to

[34] D.05-12-042, finding of fact 22.

the annual average MPR, to estimate the time periods in which a new CCGT would be dispatched, based on the CCGT's assumed operating costs. In its comments, CalWEA recommends that a lower capacity factor than 91.7% be used in the MPR Model. CalWEA argues that a capacity factor of 85.3% better reflects the Commission's direction in D.05-12-042 that the capacity factor should reflect the likely operation of a new CCGT unit.

Although CalWEA initially suggested the methodology adopted by Staff, CalWEA recommends setting a capacity factor using a simpler and more transparent methodology. CalWEA notes that the methodology developed by Staff (1) "flip-flops" from high to low capacity factors with each iteration because the IOU TODs are somewhat different, (2) double-counts start-up costs, and (3) is inadequate for accurately determining unit commitment. Therefore, CalWEA recommends adopting a simpler methodology that assumes the CCGT unit does not operate in the off-peak periods whose TOD factor is less than the variable (energy) component of the MPR as a percentage of the all-in MPR calculated using the maximum capacity technical capacity factor of 92%. This methodology results in an average capacity factor for all three IOUs of 85.3%.

SCE notes in its reply comments that CalWEA's proposal to use a simpler capacity factor calculation rather than the iterative approach that CalWEA previously suggested is without merit. The approach proposed by CalWEA would be valid only if there were no incremental fuel or O&M costs associated with starting up and shutting down the MPR proxy plant. SCE also argues that CalWEA's comment about double –counting start-up costs because the start-up costs are included in the heat rate are misleading. The only way in which start-up costs can be included in a heat rate is to assume a certain number of starts, i.e., the model calculates the number of start-ups. CalWEA's approach would not properly consider start-up costs and would not be calculating a capacity factor based on true "market behavior," as the Commission directed in D.05-12-042

In its reply comments, PG&E aggress with CalWEA that the MPR model does not accurately calculate the CCGT capacity factor because of the limited number of TODs. In addition, PG&E agrees with CalWEA that the current capacity factor methodology double-counts start-up costs and should be corrected. However, PG&E recommends that the issue regarding the number of TODs should be deferred until the development of the next MPR. Lastly, PG&E agrees with SCE that the MPR model ignores increased O&M costs associated with the number of starts and stops and that the number of starts per year should be calculated by the MPR model, rather than an input variable.

Staff agrees with SCE that CalWEA's approach would not properly consider start-up costs and would not be calculating a capacity factor based on true "market behavior," as the Commission directed in D.05-12-042. However, Staff also recognizes the limitations of the capacity factor methodology as used in the Draft Resolution and MPR Model. Specifically, the limited number of TOD periods and inadequate record on the relationship between capacity factor and the number of unit starts/stops[35] prevents the MPR Model from accurately determining unit dispatch, i.e. capacity factor.

The challenge before Staff is to adopt a capacity factor methodology that is not excessively complex and is acceptably accurate for the limited purposes of determining the MPR heat rate and capacity factor. Staff believes that the current methodology, with some modifications, meets that test. Specifically, Staff agrees that the start-up costs are double-counted so the start-up costs on the Cap Fac Tab will be deleted. Given the inadequate record on the relationship between the number of starts and the capacity factor, Staff will continue to use GE's recommendation of 125 starts per year. As the methodology is refined for future MPR calculations, Staff expects that the MPR model will be able to calculate the number of annual starts, i.e., no longer a hardwired value.

SCE's comment that the MPR model ignores the increased maintenance costs associated with starts and stops is unfounded. GE is of the opinion that the increased maintenance costs do not factor into unit dispatch until the unit reaches approximately 200 starts per year. Parties are encouraged to explore the issue of start-up costs in future MPR calculations.

5. MPRs should be Calculated for Years Beyond 2010

Both PG&E and SCE note that the Draft Resolution presents levelized costs for MPR baseload plants that would begin operating in each year from 2006 through 2010. However, some of the projects for which this 2005 MPR would be used may begin operating after 2010 (e.g., 2011 or 2010). Therefore PG&E and SCE recommend that the 2005 MPR Model be also used to derive levelized costs for a baseload MPR that would begin operating after 2010. Staff agrees with the IOUs and makes the appropriate changes in the Resolution and the MPR model.[36]

[35] The record also does not identify the relationship between the number of starts and the increased maintenance costs associated with starts and stops

[36] Staff also adopts PG&E's recommendation that the costs for MPR projects starting in 2011 and 2010 should assume that fixed and variable O&M costs will continue to escalate over the lives of the project. However, due to technological improvements, installed capital costs will be kept constant after 2010.

6. Inflation Factors need to be Corrected

In its comments, PG&E notes that the model incorrectly uses inflation rates and construction cost escalation rates. In certain places the model uses average rather than annual inflation rates and construction cost escalation rates, while in other places the model did the opposite. PG&E suggests that these inconsistencies should be eliminated by modifying the model to ensure that only annual inflation rates and annual power plant construction costs escalation rates are used. Staff adopts PG&E's recommendation and makes the appropriate changes to the Resolution and the MPR model. See CF_Data Set 9 (rows 14 and 15), Fixed_Comp (rows 13 and 15), and Var_Comp worksheets (row 15) for modifications.

7. CEC Discovered an Error in the ROE Calculation

During its review of the draft 2005 MPR model, CEC staff found that the incorrect discount rate was used in the MPR model to calculate the after tax cash flow necessary to provide the appropriate return on equity invested in the project. In solving for the after tax cash flow, the model used the 8.72% WACC as discount rate. Because the after tax cash flow is providing the return on equity investment, the appropriate discount rate to use in this calculation is the 12.68% cost of equity. This change results in after tax cash flows that provide the correct return on equity investment; the internal rate of return (IRR) for the equity investment and the after tax cash flows is the input cost of equity of 12.68%. See Control Tab (cell H29) in MPR model for modification.

8. Clerical Errors in Draft Resolution

SCE, PG&E, and SDG&E identified several clerical errors in the Draft Resolution. Staff adopted all suggested corrections and made the appropriate changes to the Resolution.

9. Additional Issues to be Addressed in Future MPR Calculations

In their comments and reply comments, PG&E and SCE identified several issues that should be addressed in the 2005 MPR calculation. Given the insufficient record, the proposed changes are beyond the scope of the 2005 MPR calculation. Parties are encouraged to explore the issues outlined below in future MPR calculations.

- MPR model needs to be updated to reflect changes to tax law[37]

---

[37] SCE Comments (pg. 1) and PG&E Reply Comments (pg. 3)

- Ensure consistency between output capacity and capacity factor of baseload plant[38]
- Seasonal variations should be incorporated into forward gas prices[39]
- Model fails to take into account volatilities of and correlation between forward natural gas prices and forward electricity prices[40]

FINDINGS

1. The 2005 MPRs were calculated and released consistent with prior Commission decisions.
2. Party comments on the 2005 MPR will guide future MPR calculations.
3. The 2005 MPR values for baseload proxy plants have been finalized for use in the 2005 Renewables Portfolio Standard (RPS) solicitations.

THEREFORE IT IS ORDERED THAT:

1. The 2005 MPRs in Appendix A are approved for use in the 2005 RPS solicitations.

2. This Resolution is effective today.

[38] PG&E Reply Comments (pg. 2)

[39] PG&E Reply Comments (pg. 3)

[40] PG&E Reply Comments (pg. 3)

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on April 13, 2005; the following Commissioners voting favorably thereon:

____

STEVE LARSON
Executive Director

APPENDIX A

Adopted 2005 Market Price Referents
At Specified Zonal Delivery Points (e.g., NP15 or SP15)
(Nominal - Dollars/kWh)

	Baseload MPR	10 year	15 year	20 year
2006	MPR All-in	**0.08317**	**0.08178**	**0.08330**
	MPR fixed component	0.02116	0.02072	0.02116
	MPR variable component	0.06201	0.06106	0.06214
2007	MPR All-in	**0.07894**	**0.07926**	**0.08098**
	MPR fixed component	0.02074	0.02074	0.02074
	MPR variable component	0.05820	0.05853	0.06024
2008	MPR All-in	**0.07681**	**0.07817**	**0.08040**
	MPR fixed component	0.02118	0.02118	0.02118
	MPR variable component	0.05563	0.05698	0.05922
2009	MPR All-in	**0.07594**	**0.07811**	**0.08074**
	MPR fixed component	0.02164	0.02164	0.02164
	MPR variable component	0.05430	0.05646	0.05910
2010	MPR All-in	**0.07604**	**0.07882**	**0.08176**
	MPR fixed component	0.02211	0.02211	0.02211
	MPR variable component	0.05394	0.05671	0.05965
2011	MPR All-in	**0.07648**	**0.07973**	**0.08292**
	MPR fixed component	0.02217	0.02217	0.02217
	MPR variable component	0.05432	0.05757	0.06075
2012	MPR All-in	**0.07728**	**0.08095**	**0.08429**
	MPR fixed component	0.02222	0.02222	0.02222
	MPR variable component	0.05505	0.05872	0.06207

Draft 2005 Market Price Referents Circulated on 3/14/05
(Nominal - Dollars/kWh)

	Baseload MPR	10 year	15 year	20 year
2006	MPR All-in	**0.07931**	**0.07825**	**0.07914**
	MPR fixed component	0.01734	0.01734	0.01734
	MPR variable component	0.06197	0.06091	0.06180
2007	MPR All-in	**0.07556**	**0.07574**	**0.07724**
	MPR fixed component	0.01752	0.01752	0.01752
	MPR variable component	0.05804	0.05822	0.05972
2008	MPR All-in	**0.07306**	**0.07423**	**0.07623**
	MPR fixed component	0.01770	0.01770	0.01770
	MPR variable component	0.05536	0.05653	0.05853
2009	MPR All-in	**0.07181**	**0.07376**	**0.07614**
	MPR fixed component	0.01789	0.01789	0.01789
	MPR variable component	0.05392	0.05587	0.05825
2010	MPR All-in	**0.07153**	**0.07407**	**0.07675**
	MPR fixed component	0.01808	0.01808	0.01808
	MPR variable component	0.05345	0.05599	0.05867

APPENDIX B

2005 MPR California and Henry Hub Gas Forecast (2006 – 2031)

Year	MPR Hhub Forecast (nominal$)	MPR CA Gas Forecast (nominal$)
2006	$11.04	$10.75
2007	$9.53	$9.52
2008	$8.36	$8.35
2009	$7.58	$7.56
2010	$7.04	$7.02
2011	$6.87	$6.86
2012	$6.71	$6.70
2013	$6.55	$6.55
2014	$6.39	$6.39
2015	$6.45	$6.46
2016	$6.64	$6.66
2017	$6.94	$6.99
2018	$7.16	$7.22
2019	$7.51	$7.58
2020	$7.80	$7.89
2021	$8.08	$8.18
2022	$8.41	$8.53
2023	$8.74	$8.88
2024	$9.10	$9.25
2025	$9.46	$9.62
2026	$9.78	$9.96
2027	$10.13	$10.33
2028	$10.47	$10.68
2029	$10.83	$11.06
2030	$11.25	$11.49
2031	$11.57	$11.83

APPENDIX C

Calculation of 2005 Installed Capital Costs

Cosumnes (SMUD)

Background:
The Cosumnes Combined-Cycle Gas Turbine (CCGT) Project has two phases. SMUD is currently building the first 500 MW plant (Phase 1) and then it will determine by 2006 if it will build the second 500 MW plant (Phase 2) or defer construction. The plant is being built at a rural site in Sacramento County about 25 miles southeast of Sacramento.

The plant is located on a 30-acre site about a half-mile south of the now closed Rancho Seco Plant. This location allows the reuse of existing water systems, switchyards, and transmission lines that are already in place. The location of the plant site, within 2,480-acres of SMUD property, will help to reduce costs and make the best use of existing SMUD customer resources.[41]

Calculation:
The Cosumnes Project Revenue Bonds Series 2006 document[42] shows a Total Construction Cost of $435 million at pages 4, 19, A-23, and A-24. However, on page 4, it is noted that the Total Construction Cost does not include interconnection facilities (water, gas, electric). Consequently, Staff added interconnection costs[43], which were estimated at 5% of $435 million, and a $20 million adjustment for dry cooling.

---

[41] http://www.smud.org/cpp/project.htm

[42] SMUD Bond Series document available online at http://www.munios.com/re.asp?ID=%9D%9Dw%81br%8Bi%85%95%87%81%BE%B7%99%93%A5%8F%C3%9A%97%97%87ik%8B%82 or type "Cosumnes" or "Sacramento" in the search box located in the upper left corner of the www.munios.com homepage. Users may have to register with the website, but documents can be downloaded at no cost.

[43] In its 2003 Testimony, CEERT described these costs as "interconnection to the electric grid, interconnection to the local distribution company's gas system or an interstate pipeline, water interconnections, sewage interconnections, and other so-called "linears" (CEERT, R.01-10-024, RPS Phase, April 1, 2003, p.II-10).

Install Capital Cost Inputs (2006$)	Cosumnes (SMUD) Combined-Cycle 500 MW	
	(Million $)	$/kW
Capital Cost Investment - Overnight Costs	$435	$870
Interconnection (natural gas, water, electric)	$21.75	$44
Environmental Review & Permitting	Included in Instant Capital Costs Shown Above	Included in Instant Capital Costs Shown Above
Emissions offsets		
Dry Cooling Adjustment	$20	$40
Contingency	-	-
AFUDC	-	-
EITC	-	-
Other or Subtotal	-	-
Total "Turn-Key" Capital Costs (2006$)	$477	$954

Palomar

On June 9, 2004, the Commission issued D.04-06-011, which approved a Turnkey Acquisition Agreement (TAA) between SDG&E and Palomar Energy, LLC (Palomar Energy) (a subsidiary of Sempra Generation), dated January 29, 2004. Palomar is a 500 MW (base load)/555 MW (peaking load) combined cycle natural gas-fired generation plant located in Escondido, California. SDG&E will assume care, custody and control and risk of loss under the TAA upon closing, which SDG&E presently expects will occur on or about

In their 2005 MPR comments, several parties recommended that that the Commission use Palomar costs to derive the 2005 MPR installed capital costs. CalWEA proposed the most detailed proposal but it incorrectly calculated its proposed total cost per kW ($1,017/kW)[44].

Staff contacted Crossborder Energy and learned that the $1,017/kW estimate was derived from values shown on Attachment A to the CalWEA Brief, "Palomar Plant Information." On Attachment A in the Annual Average column, Lines 3

[44] CalWEA Brief, Table 1, pp.5-6, and p.11

and 11 were added together, and the resulting sum was divided by 500 MW[45]: [$467.3251 million + $41.0398 million = $508.36 million] ÷ 500 MW = $1,017/kW.

There are two errors in this calculation. The $467 million figure should be $484.343 million, and the $41 million figure should not be included. First, CalWEA states that both figures on Lines 3 and 11 (CCC Brief, Attachment A) were taken from the Direct Testimony of Mike Calabrese, SDG&E, November 1, 2004, in the Palomar Application, A.04-11-003, specifically, Attachment A & B of the Calabrese Testimony. Upon reviewing the actual Direct Testimony of Mike Calabrese, it is clear that the $467 million figure used by CalWEA is an average of a mid-2006 figure and an end-of-year 2007 figure. This is problematic because nominal dollar amounts from different years are combined. In addition, the $467 million figure is reduced by accumulated depreciation and accumulated deferred taxes, both reductions from the initial balance figure. Instead, it is the initial balance figure of $484.343 million that should be used to represent the total cost of the Palomar project, given that it is the amount that would be put into rate base. [46]

Second, CalWEA's addition of $41 million to the $467 million figure is in error because an annual Rate of Return (ROR) on rate base figure cannot be added to a total rate base amount to represent a total cost or purchase price. The $41 million figure is a year-specific cost paid by ratepayers as a payment for the Palomar asset that is in rate base.

Thus, the total cost for Palomar can be fairly represented by (1) the Initial Balance figure of $484.343 million as shown in the Calabrese Testimony, Attachment B; and (2) the addition of $20 million for a dry cooling system. This results in a total cost of $504 million or $1,009/kW. The $74 million shown on Line 9 of the Energy Division spreadsheet for Palomar is merely the difference between the $504 million and the overnight base purchase price of $410 (Calabrese Testimony, Attachment B). The $74 million includes base purchase price adjustments, other adjustments, general plant, materials and supplies, and working cash (Id.)

[45] CalWEA incorrectly used the baseload nameplate capacity – peaking nameplate (555 MW) should have been used

[46] Source for the $410 and $484 million figures: Direct Testimony of Michael Calabrese with Attachments A-C, SDG&E, November 1, 2004, Attachment B, Sheet 1 of 1.

Install Capital Cost Inputs (2006$)	Palomar (San Diego) Combined-Cycle 555 MW	
	(Million $)	$/kW
Capital Cost Investment - Overnight Costs	$410	$739
Interconnection (natural gas, water, electric)	Included in Instant Capital Costs Shown Above	Included in Instant Capital Costs Shown Above
Environmental Review & Permitting		
Emissions offsets		
Dry Cooling Adjustment	$20	$36
Contingency	-	-
AFUDC	-	-
EITC	-	-
Other or Subtotal	$74	$134
Total "Turn-Key" Capital Costs (2006$)	$504	$909

Appendix D
2005 MPR Gas Forecast Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Notes
1	Henry Hub Forecasts /1	CERA, PIRA, or Global Insight /2	$/MMBtu	N/A	20 yr. Henry Hub forecast (private - purchased)
2		Energy Information Administration (EIA)	$/MMBtu	N/A	EIA (Feb. 2006) - 20 yr.wellhead prices adjusted 10.8% to reflect Henry Hub forecast (public)
3	General Inputs	Transaction Cost	$/MMBtu	$0.082	D.04-06-015, pg. 26, reafirmed in D.05-12-042 (pg. A-7)
4		Transportation Escalation Rate	Percent-%	2.45%	Average of EIA 2006 GDP Chain-Type Price Index. See 2005 MPR model - Delivery_Tar Tab (Cell E9)
5		20-year WACC	Percent-%	8.72%	2005 MPR model - Cost Cap Tab (Cell D9)
6	Municipal Surcharge	SoCal Muni Surcharge	Percent-%	1.553%	Schedule G-MSUR - http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf
7		PG&E Muni Surcharge	Percent-%	1.130%	PG&E Rate Schedule GC-P: (1) http://www.pge.com/rates/tariffs/GCP_Current.xls and (2) http://www.pge.com/rates/tariffs/GSUR_Current.xls
8	PG&E Gas Distrib. Rate	Customer Access Charge	$/day	$179	http://www.pge.com/tariffs/pdf/G-EG.pdf
9		Proxy Plant Capacity	MW	500	2005 MPR model - Delivery_Tar Tab (Cell E15)
10		Heat Rate	MMBtu/MWh	7.28	2005 MPR model - Delivery_Tar Tab (Cell E16)
11		Capacity Factor	%	92%	2005 MPR model - Delivery_Tar Tab (Cell E17)
12		Monthly Gas Consumption	MMBtu	80,231	(Row 8 * Row 9* Row 10) * 24 hours
13		Unit Cost of Customer Access Charge	$/MMBtu	$0.0022	Row 7 / Row 11
14		Transportation Charge	$/MMBtu	$0.2337	http://www.pge.com/tariffs/pdf/G-EG.pdf
15	SoCal Gas Distrib. Rate	Customer Charge	$/month	$0.00000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
16		Transmission Charge	$/MMBtu	$0.3954	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf
17		Interstate Transportation Cost Surcharge	$/MMBtu	$0.0000	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf

1/ The Henry Hub forecasts are inputs for the MPR - Henry Hub forecast - there are no specific baseload values.
2/ Due to contractual obligations requiring the CPUC to keep the forecast confidential, staff can not reveal which of the three firms the forecast was purchased from.

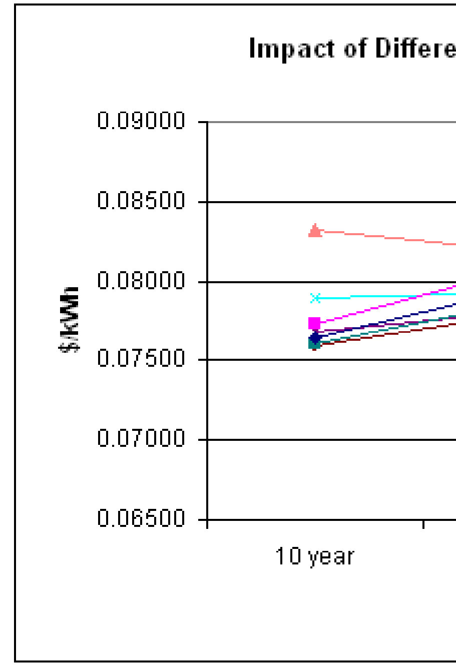
Appendix E
2005 MPR Non-Gas Inputs

Row No.	Input Category	Input	Units	Baseload Inputs	Escal. Rates/yr.	Notes
1	Capital Inputs	Total capital cost January 1 - 1st operational yr.	$/kw	$939	2.10%	Per D.05-12-042, Staff conducted a survey of actual plant costs in CA. Four plants were selected and an average was calculated
2		Fixed O&M	($/kW-yr) 1st operational yr.	$13.70	2.45%	See Attachement F, Mountainview Application (FERC Docket ER04-316). Highest and lowest values were deleted from Wharton data set, Palomar and CC8 were added, and an average value was calculated
3		Variable O&M	(mills/kWh) 1st operational yr.	$2.43	2.45%	See Attachement F, Mountainview Application (FERC Docket ER04-316). Highest and lowest values were deleted from Wharton data set, Palomar and CC8 were added, and an average value was calculated
4		New & Clean heat rate	Btu/kWh HHV	7076	n.a.	Per D.05-12-042, Staff used the the "new & clean" heat rate for an F-Series (GE S207FA) CC Turbine, adjusted for Higher Heating Value
5		Heat rate degradation factor	Percent-%	1.69%	n.a.	Per D.05-12-042, Staff contacted GE for an appropriate heat rate degradation factor for an F-series CC turbine. GE provide a degradtion curve that calculated the average degradation over the life of the project.
6		Average heat rate	Btu/kWh HHV	7347	n.a.	Average heat rate over life of plant, taking into account the impact of Higher Heating Value, degradation, dry cooling, and starts/stops
7	Finance Inputs	20-year WACC	Percent-%	8.72%	n.a.	Weight-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
8		Cost of LT Debt	Percent-%	8.03%	n.a.	Per D.05-12-042, Cost of Debt (industrial firms) = risk free rate (20 year T-Bill) + risk premium (mid point between BBB & B+)
9		Cost of Equity	Percent-%	12.68%	2.00%	Per D.05-12-042, Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity)
10		Debt as % of total cost	Percent-%	50%	n.a.	Per D.05-12-042, LT debt ratio for BBB rated company
11		Debt Term	Years	20	n.a.	Adopted in D.04-06-015 and reaffirmed in D.05-12-042
12		Insurance as % of plant cost	Percent-%	0.60%	2.45%	Same value used for 2004 MPR. Energy Division contacted insurance brokers for quotes and calculated an average value.
13	Power Delivery Inputs	Transformer Loss Factor	Percent-%	0.50%	n.a.	Loss factor recommended by parties and used in 2004 MPR calculation - Parties did not propose changes for 2005
14		Generation Meter Multiplier (GMM) to load center	Percent-%	98.5%	n.a.	Per CCC recommendation (comments, pg. 13) , Staff calculated the 2005 system annual average for GMMs used data provided by CAISO
15		Capacity Factor	Percent-%	92%	n.a.	Per D.05-12-042, Staff developed a methodology, using the average of IOU TODs, to calculate a range of capacity factors. See Cap_Fac Tab in 2005 MPR model
16	Tax Rate Inputs	Federal Tax Rate	Percent-%	35%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation - Parties did not propose changes for 2005
17		State Tax Rate	Percent-%	8.84%	n.a.	Tax rate proposed by the parties and used in the 2004 MPR calculation - Parties did not propose changes for 2005
18		Total Effective Tax Rate	Percent-%	40.75%	n.a.	Effective Tax = Federal Tax * (1 - State Tax) + State Tax
19		Property taxes as % of plant cost	Percent-%	1.20%	n.a.	Same value used for 2004 MPR. Energy Division averaged the property tax rates for 14 counties in which power plants were constructed (or under construction) in the last 5 years.
20	Gas Forecast	20yr gas forecast - 2006 levelized	$/MMBtu	$7.91	n.a.	Output from CA_Gas_Forecast Tab (Cell L36) in 2005 MPR model

2005 MPR Summary

Baseload MPR Matrix - Based on Project Online Date (Nominal $/kWh)

	Baseload MPR	**10 year**	**15 year**	**20 year**
2006	MPR All-in	**0.08317**	**0.08178**	**0.08330**
	MPR fixed component	0.02116	0.02072	0.02116
	MPR variable component	0.06201	0.06106	0.06214
2007	MPR All-in	**0.07894**	**0.07926**	**0.08098**
	MPR fixed component	0.02074	0.02074	0.02074
	MPR variable component	0.05820	0.05853	0.06024
2008	MPR All-in	**0.07681**	**0.07817**	**0.08040**
	MPR fixed component	0.02118	0.02118	0.02118
	MPR variable component	0.05563	0.05698	0.05922
2009	MPR All-in	**0.07594**	**0.07811**	**0.08074**
	MPR fixed component	0.02164	0.02164	0.02164
	MPR variable component	0.05430	0.05646	0.05910
2010	MPR All-in	**0.07604**	**0.07882**	**0.08176**
	MPR fixed component	0.02211	0.02211	0.02211
	MPR variable component	0.05394	0.05671	0.05965
2011	MPR All-in	**0.07648**	**0.07973**	**0.08292**
	MPR fixed component	0.02217	0.02217	0.02217
	MPR variable component	0.05432	0.05757	0.06075
2012	MPR All-in	**0.07728**	**0.08095**	**0.08429**
	MPR fixed component	0.02222	0.02222	0.02222
	MPR variable	0.05505	0.05872	0.06207



	component			